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Evolutionary optimisation for CO₂ storage design using upscaled models: Application on a proximal area of the Forties Fan System in the UK Central North Sea

Masoud Babaei^a, Indranil Pan^a, Anna Korre^a, Ji Quan Shi^a, Rajesh Govindan^a, Sevket Durucan^{a*}, Martyn Quinn^b

^aDepartment of Earth Science and Engineering, Royal School of Mines, Imperial College London, London SW7 2BP, United Kingdom

^bBritish Geological Survey, Murchison House, Edinburgh, EH9 3LA, , United Kingdom

Abstract

Optimisation of injection rates is an important design consideration for meeting operational objectives and ensuring long term geological storage of CO₂ in saline aquifers. The optimal design should also take into account the uncertainties associated with the subsurface (e.g., petrophysical attribution and structural relationships). Detailed geological models along with different realisations for handling uncertainties increase the computational overheads, making the optimisation problem intractable. To circumvent this problem, upscaled models can be used to speed up the identification of optimal solutions. Nevertheless, a grid resolution, which does not compromise the accuracy of the optimisation in an upscaled model, must be carefully determined. The methodology described in this paper aims to address this requirement. In this study, a 3D geological model, comprising the main oil reservoirs of the Forties and Nelson hydrocarbon fields and the adjacent saline aquifer, was built to examine the use of coarse grid resolutions to design an optimal CO₂ storage solution for this area within the UK Central North Sea. Simulation results for single objective optimisation show that an upscaled grid resolution can be identified which is a trade-off between accuracy and computational time. The outlined methodology is generic in nature and can be ported to other similar optimisation problems for CO₂ storage.

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* Corresponding author. Tel.: +44-20-7594-7354; Fax: +44-20-7594-7444.

E-mail address: s.durucan@imperial.ac.uk

1. Introduction

In the design of CO₂ storage site operation, it is important that potential risks are minimised or entirely avoided. One such potential risk is CO₂ migration outside the targeted geological storage complex. This might occur if the CO₂ plume is allowed to reach the structural spill point of the targeted zone. Moreover, the CO₂ injection should not affect regions outside the licensed area boundaries and there should be no migration of CO₂ into the neighbouring fields.

A number of researchers have focused on single and multi-objective optimisation for CO₂ storage with different optimisation variables and performance measures. Several design options for the injection operations were investigated by Bergmo *et al.* [1]: injection of CO₂ without water production; injection into several wells to distribute the injected fluids and reduce the local pressure increase around each injection well; and injection with simultaneous production of water from one or more wells. The optimal well placement, CO₂ injection rate and cycling brine injection for minimising the post-injection mobile CO₂ were tested by Cameron and Durlofsky [2]. Co-optimisation of CO₂ storage and net present value from enhanced oil recovery by CO₂ injection is addressed by Leach *et al.* [3].

As the computationally expensive design procedure involved in optimising large subsurface models is a major concern, the use of upscaled models is more justified. In this line of research, Cameron and Durlofsky [2] used a modest level of coarsening (by a factor of two in each direction) in their non-gradient-based optimisation and assessed the impact of grid resolution on the optimised solutions. They observed a reasonable correspondence in mobile CO₂ fraction between the models. Yamamoto and Doughty [4] reported a study of gridding effects on CO₂ storage simulation and concluded that there is an underestimation of gravity override and maximum plume extent by a coarse grid. They also recommended localised upscaling for capturing salt precipitation near the wells.

The objective of this paper is to illustrate the use of optimisation techniques in conjunction with upscaled models of heterogeneous storage complexes in the Central North Sea, with the aim to minimise the risk of lateral migration of injected CO₂ reaching the system spill point. One important aspect considered in this process is that the upscaled static models should account for reservoir heterogeneity while ensuring that the detailed system is represented adequately. The storage complex used to illustrate the approach comprises reservoirs of the Forties and Nelson oilfields and their surrounding aquifer. These two fields have already been cited in the literature for high potential for CO₂ storage [5]. In this study, a fine resolution static model of the Central North Sea Paleocene/ Eocene Forties Sandstone Member has been constructed and used in this study to provide a sufficiently complex environment for evaluation of the upscaled models.

2. Evolutionary optimisation and objective function

In general, a wide variety of optimisation techniques using gradient descent methods may be used if the objective function is smooth and analytically tractable. However, this is not commonly the case for subsurface models. Additionally, if the functional form is known to be convex, then semi definite programming or other linear-matrix-inequality-based techniques will be more expedient, as commercial solvers that solve such problems in polynomial time exist.

From the optimisation point of view, simulators, such as ECLIPSE E300, used in this study, need to be treated as black box models. Therefore, the traditional methods of optimisation are not suitable in general. Intelligent bio-inspired optimisation techniques like Genetic Algorithm (GA) or Particle Swarm Optimisation are well suited to this kind of problem and, unlike the traditional gradient-based optimisers, can handle discontinuous, noisy and stochastic objective functions. In this study, a real coded GA is used for optimisation. The objective function considered for minimisation is

$$J(\mathbf{x} \cdot Q) = \sum_{t=0}^{t_{\max}} \sum_{i=1}^{M_b} v_F^{i,t}(\mathbf{x} \cdot Q) \quad (1)$$

where $v_F^{i,t}(\mathbf{x} \cdot Q)$ is the mobile CO₂ present in gridblock i at time t , t_{\max} is the time duration for simulation, M_b is the number of gridblocks in the region of the aquifer lying outside the assumed licensed regions of the Forties and

Nelson reservoirs. These reservoir simulator outputs are reported in kg-mole and converted to million tonnes for reporting purposes. They depend on the total flow rate, Q , and the allocation vector of injection rates, \mathbf{x} , for the wells that are present in the system.

The GA encodes the solution variables as genes and initialises a population randomly within the lower and upper bounds of the search space. The fitness of each of the genes is evaluated by using the user specified objective function. The algorithm then uses crossover and mutation operators to evolve the next generation of the population. A few elite genes with the highest fitness function values are directly passed on to the next generation to preserve the best obtained solutions. The algorithm iteratively performs these operations to produce a newer population of genes until a specified number of generations are completed. The best gene in the last generation represents the optimised solution obtained by the algorithm.

3. Upscaling of the geological model

The chosen study area is located on the Forties-Montrose High in the UK Central North Sea and includes the Forties and Nelson hydrocarbon fields [6]. The hydrocarbon reservoir consists of submarine fan deposits of the Paleocene/ Eocene Forties Sandstone Member overlain by Lower Eocene shale [7], [8]. The reservoir is located in the proximal inner (interbedded sand/shale) to middle (mainly massive sand) part of the Forties Fan system [7] and is mostly channelised and characterised by high net to gross sandstone ratios, good porosities and high permeabilities. A geological model of the two hydrocarbon fields and the surrounding aquifer has been constructed (Fig. 1). It contains 8 zones: Zone M (the overlying top seal), the 'Upper Sand' (Zones L, K, J, H, F, and E), and the 'Lower Sand' (Zone D). The two sand zones are separated by a continuous and uninterrupted mudstone layer, which acts as a vertical barrier to pressure communication and fluid flow between the Upper and Lower sands [9].

This study focuses on one of the zones in the geological model, namely zone E, to illustrate the proposed optimisation methodology. Zone E is composed of thick bedded sandstone; and interbedded sandstone and mudstone corresponding to high and low density turbidites respectively. The base of the zone is sealed from the deeper Zone D by a mudstone layer, so that there is no communication between the two. The top of Zone E is in communication with Zones F and Lower H which are discordant (have different channel layout and structure) and are of similarly variable facies distribution. As pointed out previously, poor vertical communication between zones is expected due to mudstone and shale intervals. Therefore, using one zone of the system does not compromise the generality of the methodology.

The geological model (Zone E section) is laid out on a $211 \times 160 \times 8$ resolution grid with an average gridblock length of 200 m in x and y directions and an average thickness of six metres, referred to as the *fine* grid in this study. The model comprises 196,131 active gridblocks. Model upscaling is limited only to the lateral direction and the vertical resolution of the fine model is maintained in the upscaled grids as the simulated upward migration of CO_2 is more sensitive to the vertical resolution. Two progressively coarser grids were considered: an *intermediate* grid ($70 \times 54 \times 8$ blocks with average gridblock length of 600 m, three times that of the fine grid) and a coarse grid ($42 \times 31 \times 8$ blocks with average gridblock length of 1,000 m).

The horizontal, vertical permeability and porosity of Zone E are shown in Fig. 2. The figure illustrates only one of the three realisations (no. 1) used in simulations. The corresponding petrophysical properties for the *intermediate* and *coarse* grids were calculated for the three realisations. The upscaling algorithm used for porosity and net-to-gross property is arithmetic volumetric averaging. For permeability the single-phase non-tensorial pressure solver method ([10], [11]) is used. Figs. 3 and 4 illustrate the property distributions for the *intermediate* and *coarse* grids for realisation no. 1 respectively.

4. Simulation results

The eight wells used for CO_2 injection simulation are shown in Fig. 1b. Two of the four wells in Forties (vertical wells) were used for peripheral water injection during oil production and two others (deviated wells) were used to produce oil at platform FC (Forties Charlie) located in the western flank of the oilfield. Four wells in Nelson (all deviated) were all oil production wells drilled from a single platform located in the middle of the oilfield. These wells were selected because they were drilled in the channel area of Zone E.

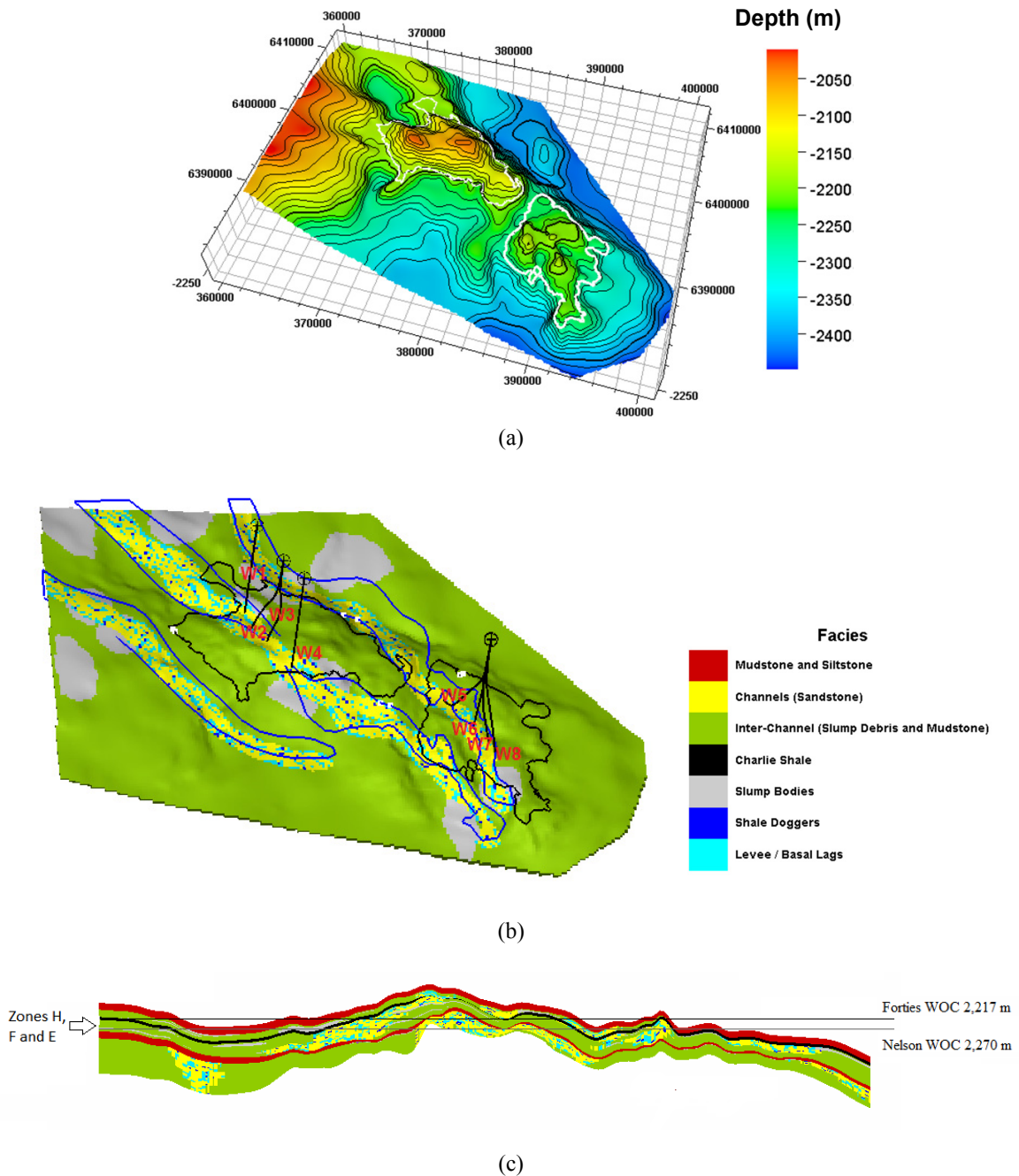


Fig. 1. (a) Top surface depth of the aquifer in metres, with Forties and Nelson oil fields indicated by white polygons (b) Facies map used in geological modelling, injection wells indicated by W1 to W4 in Forties and W5 to W8 in Nelson, and flow line polygons indicated by blue lines. (c) Cross sectional view of the Forties Field structural closure and facies distribution. Zones H, F and E are capped by the Charlie Shale (in black) and overlie a mudstone layer (in red).

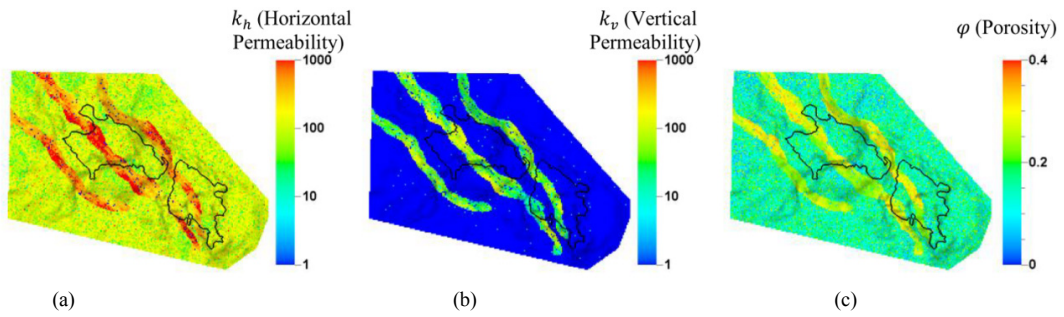


Fig. 2. A *fine* grid realization of (a) horizontal permeability (millidarcy), (b) vertical permeability (millidarcy) and (c) porosity (fraction).

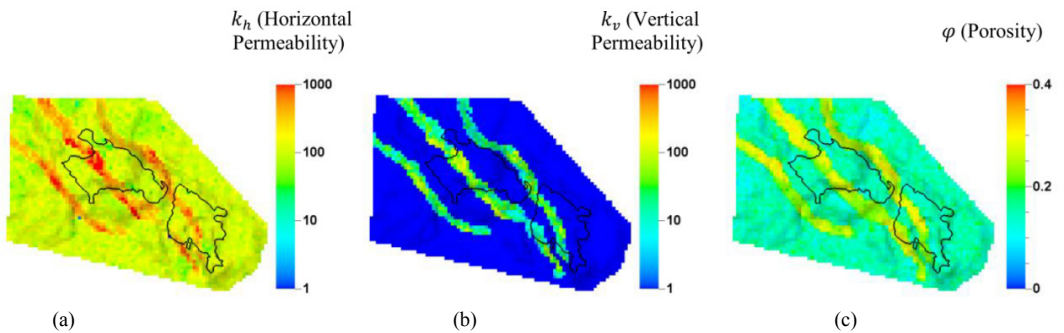


Fig. 3. The *intermediate* grid upscaling of (a) horizontal permeability (millidarcy), (b) vertical permeability (millidarcy) and (c) porosity (fraction).

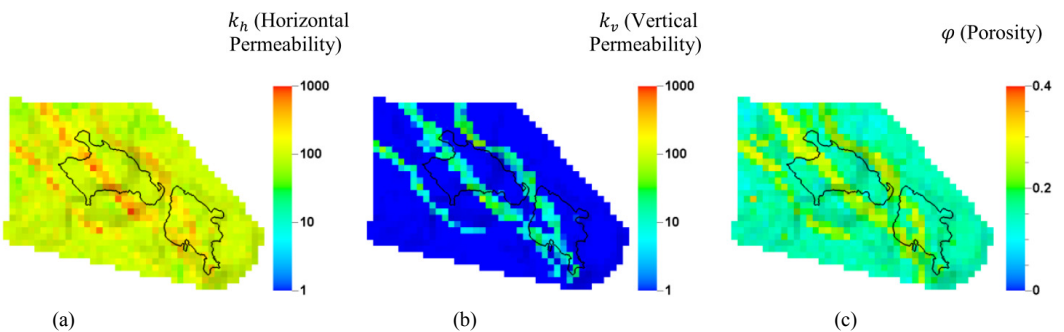


Fig. 4. The *coarse* grid upscaling of (a) horizontal permeability (millidarcy), (b) vertical permeability (millidarcy) and (c) porosity (fraction).

During the simulations, a total of 150 million tonnes of CO₂ are injected, at 5 million tonnes of CO₂ per year, over 30 years, and an additional 50 years are allowed for stabilisation and investigation of potential migration of CO₂. The simulations were run on a Windows based operating system with a 3.40GHz CPU and 16.0 GB RAM. Each of the *fine*, *intermediate* and *coarse* grid resolutions of the model takes around 2,087, 114 and 24 seconds to run, respectively. These numbers must be multiplied by 600 (20 populations \times 30 generations) to indicate the time required for optimisation of each model and each grid. As shown in Fig. 5, the difference in run times between the *fine* and the *intermediate* grids is higher than that between the *intermediate* and *coarse* grids, suggesting that the run time does not scale linearly with the size of the model. From the run-time point of view, there should be an optimal grid that produces acceptable errors in accuracy, which is an important trade off consideration.

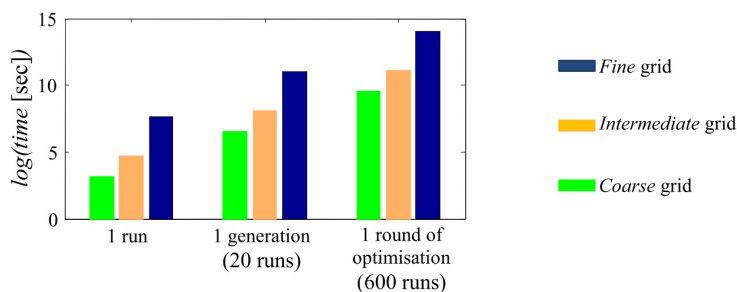


Fig. 5. A comparison of the run times required for a single run, a generation of GA algorithm including 20 runs and a round of GA algorithm including 600 runs of ECLIPSE simulations.

4.1. Optimisation results

The convergence of the final optimum solution from one generation to another for the three realisations fine, intermediate and coarse grids are shown in Fig. 6. In this figure, the best and mean fits refer to the best and mean value in each generation and the convergence is assured only when the best fits do not vary significantly over the iterations. Additionally, the difference between the mean and best fits should narrow down to show that, if the algorithm were allowed to continue for another generation, that generation's solutions will not diverge significantly from those of the previous one. The values of best fits show that, while the intermediate grid marginally underestimates the mobile CO₂ outside the licensed regions, the coarse grid significantly overestimates it.

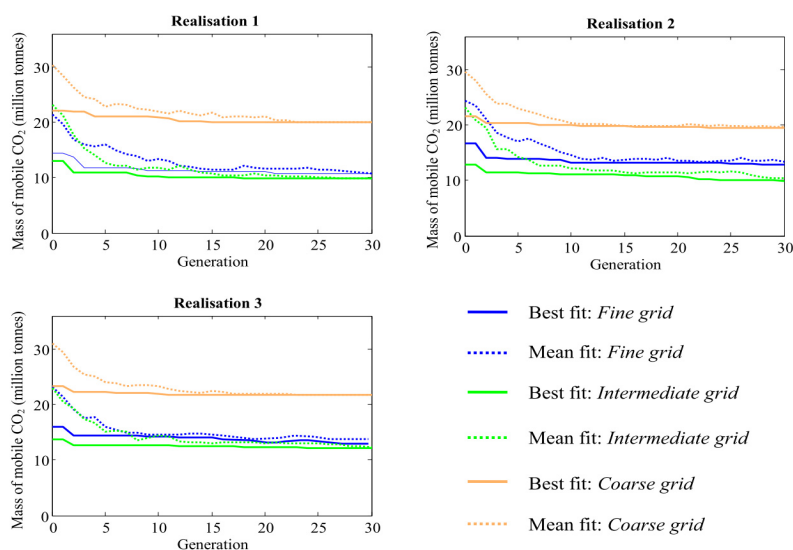


Fig. 6. The convergence of the optimum solutions for the three grids and the three realisations after 30 generations of GA.

In order to compare the performances of the *intermediate* and *coarse* grids and to investigate the reliability of solutions of these grids for optimisation, the solutions are used in the *fine* grid simulation. The simulation runs denoted as “*Intermediate-in-Fine*” and “*Coarse-in-Fine*” hereafter refer to these cases.

Fig. 7 shows how optimised solution of the *fine* grid reduced mobile CO₂ outside the licensed regions at the end of simulation. Compared to the *base case*—where the total rate is equally divided between the eight wells, the final result of optimisation, referred to as *best fit*, reduced mobile CO₂ by 48%. Also shown in Fig. 7 is the mobile CO₂ obtained by “*Intermediate-in-Fine*” and “*Coarse-in-Fine*” cases. The results are very reassuring, showing that the

“*Intermediate-in-Fine*” case is reproducing the *fine* grid’s best fit almost exactly and that the “*Coarse-in-Fine*” case is reproducing the *fine* grid’s best fit with a negligible error. This confirms that all the solutions for the injection rates are actually optimal for the realisations that they have been derived for. Finally, Fig. 8 illustrates the CO₂ saturation for base case and the best fit at the end of injection time for the top layer that exhibits the larger spread of mobile CO₂ outside the license area.

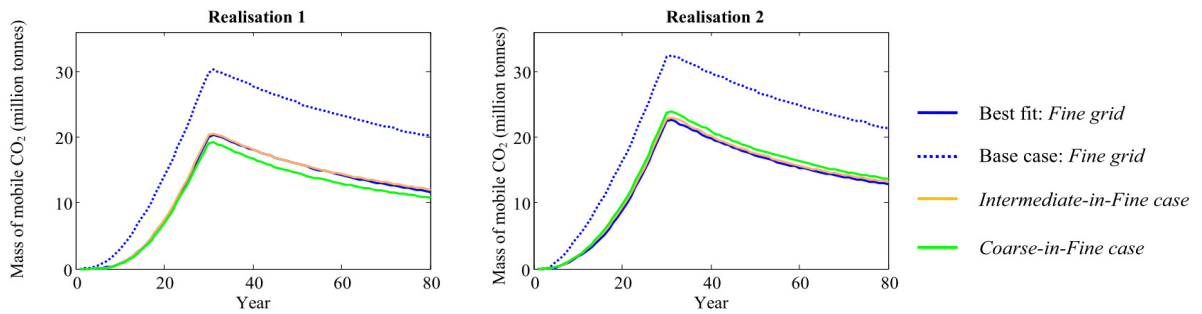


Fig. 7. The mass of mobile CO₂ outside the licensed regions obtained by fine grid simulations in the single objective optimisation case for the first two realisations.

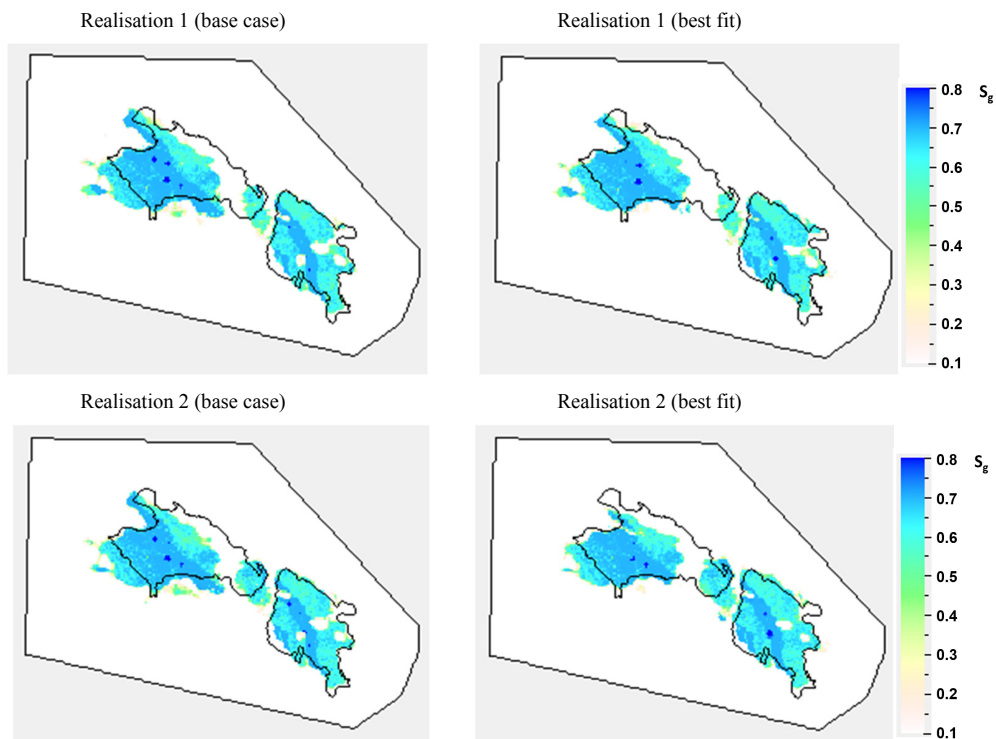


Fig. 8. The CO₂ saturation for the top layer at the end of injection period for the base case and best fit of the two realisations used in the simulations.

5. Conclusions

This study has shown that upscaled models for the optimal design of CO₂ storage operations are feasible only if careful preliminary assessment of the performance of such models is compared with the geologically detailed fine scale models. When allocating the total available rate of CO₂ between a group of pre-existing injection wells, upscaling reduced the computational runtime drastically. Future work might be directed towards optimisation considering other operational design parameters, such as the number and locations of wells, the maximum allowable bottomhole pressure during injection etc. In all such cases, the upscaling needs to be quantitatively re-evaluated and the approach presented in this work can be used for this purpose.

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